Application of Flow Computers for Gas Measurement and Control

Al Majek

Oil & Gas Production Area Technical Manager

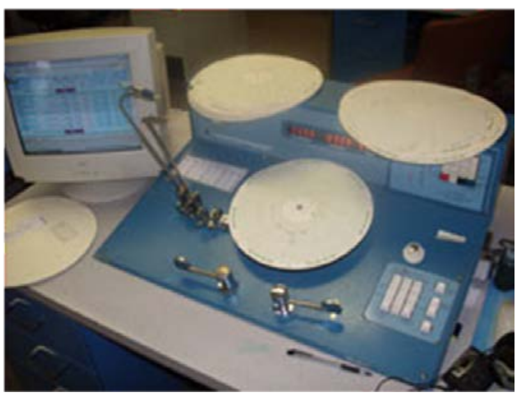
Emerson Remote Automation Solutions

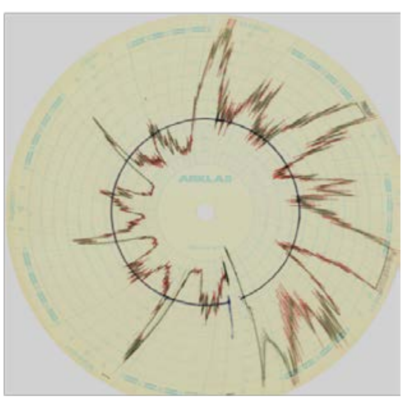
6005 Rodgerdale Road

Houston, Texas 77072 USA

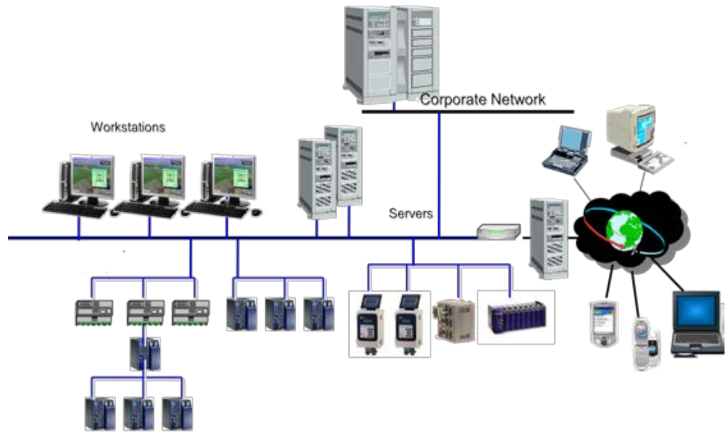
INTRODUCTION

The measurement of gas has progressed considerably since the days of paper charts and manual integration.





While still in use today, the technology has moved increasingly to microprocessor based flow computers. Such devices allow for greater measurement accuracy, increased control functionality, and are readily integrated into a company's enterprise computer networks.



Components of an Electronic Flow Meter

Primary, Secondary, Tertiary Devices

API Chapter 21.1, a document published by the American Petroleum Institute (API), describes fundamental elements in natural gas measurement:

- ***Primary device*****:** Orifice, turbine, rotary, or diaphragm measurement devices that are mounted directly on the pipe and have direct contact with the fluids being measured.

Orifice Meter *Vortex Meter* *Ultrasonic Meter*

- ***Secondary device***: provides data such as flowing static pressure, temperature flowing, differential pressure, relative density, and other variables that are appropriate for inputs into the tertiary device.

Delta Pressure Transmitters

- ***Tertiary device:*** is an electronic computer, programmed to correctly calculate flow within specific limits that receives information from the primary and/or secondary devices.

Our interest lies with the electronic computer, or flow computer.

Industry Sectors

There are three sectors of the measurement industry generally referred to as Upstream, Midstream, and Downstream metering. It is worth noting that the Downstream sector is viewed somewhat differently between the gas and liquid sides of the Oil and Gas industry as depicted below.

Upstream: This term is used commonly for the searching for and subsequent recovery of crude oil and natural gas - sometimes referred to as the Exploration and Production sector.

***Midstream*:** After producing the fluid, the product must be moved to market. Pipelines are typically used to transport products; this sector is referred to as the Midstream portion of the industry.

Downstream- Gas: After the gas is produced (Upstream) and transported (Midstream) it is then delivered to the gas distributors (Downstream), the natural gas may have been measured at least four times prior to arrival at your home. Downstream refers to the final delivery of the gas to homes, businesses, and industries.

Downstream- Liquids: In the case of liquids, the downstream segment begins with a crude oil refinery or Natural Gas Liquid fractionation facility.

Applications

Measurement Application - Custody Transfer

The most driving factor behind Electronic Flow Measurement from the inception of the technology has been applications involving Custody Transfer. Custody Transfer locations are the cash registers of the industry. A measurement station may include metering runs for multiple streams such as a “city gate” station where natural gas is transferred from a transmission pipeline. Accurate measurements are required to meet contractual requirements between companies or common carriers such as pipelines. These measurements are often required to be implemented by local government entities for tax purposes, requiring extensive reporting and data acquisition capabilities. Applications of this nature may be found in all three segments of the aforementioned sectors.

FINANCIAL UNCERTAINTY IN OIL TRANSFER AT $89.00/BBL

Yearly Financial Uncertainty			
BPH	Price of Oil per Barrel		$89.00
1000	$780,157	$1,950,392	$3,900,785
2000 (6” Line)	$1,560,314	$3,900,785	$7,801,569
4000 (8” line)	$3,120,628	$7,801,569	$15,603,138
8000 (10” Line)	$6,241,255	$15,603,138	$31,206,276
16000 (16” Line)	$12,482,511	$31,206,276 Typical	$62,412,553
32000 (24” Line)	$24,965,021	$62,412,553	$124,825,106
64000 (36” Line)	$49,930,042	$124,825,106	$249,650,212
Uncertainty	0.10%	0.25%	0.50%

In the gas industry virtually all calculations meet standards set by the American Gas Association (AGA) and the American Petroleum Institute. For the US market, these standards include:

AGA Report No. 3, Orifice Metering of Natural Gas Part 3: Natural Gas Applications

AGA Report No. 7, Measurement of Natural Gas by Turbine Meter

AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases

AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters

AGA Report No. 10, Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases

API MPMS Chapter 21.1: Flow Measurement Using Electronic Metering Systems - Section 1: Electronic Gas Measurement

Interestingly, there is not a certification agency for adherence to these standards. Most manufacturers will submit their designs to independent groups for testing. The result is a report indicating that the design is compliant to the particular standards involved. Groups such the Southwest Research Institute (SWRI) and the Colorado Engineering Experiment Station, Inc (CEESI) are commonly used by the industry.

Most all electronic gas measurement systems have a way to collect data remotely from metering sites. There is still the practice of manually driving to the sites and collecting the measurement data via a PC or some type of hand held device. Generally, though, there is a Host Supervisory Control and Data Acquisition (SCADA) computer system in place that resides in the corporate office or in the field office.

This system contains a polling software package that is designed to communicate via radio, satellite, or hard wire to the remote location. Usually these systems communicate once an hour, or on a more frequent basis to the well sites to both assure the processes are running properly and to retrieve timely information.

Most polling/Host systems have features to allow retrieval of data along with editing of historical data.

Midstream Application – Wireless Instrumentation

Beginning in early 2000, wireless instrumentation began to appear in industrial applications on an increasing scale. As the name implies, these Secondary Devices eliminate the cost of wiring and the physical limitations associated with flow computer I/O. However, battery lifetimes can be a very critical consideration.

Wireless Transmitter

One consideration for battery lifetime is ambient temperature. Using a pressure transmitter as an example, temperature effects are shown below:

Device: Pressure Transmitter, Sample Rate 16 seconds

AMBIENT TEMP.	ESTIMATED BATTERY LIFE
86°F	7.0 years
0°F	6.3 years
-40°F	5.6 years

Of much greater impact is the sampling frequency. In slow changing applications like tank level measurement, or non-critical applications such as temperature in non-custody transfer location, the requirement for data may be on a once every 16 second basis. The common midstream application, however, is custody transfer, which by API 21.1 standards requires a sample every second. Battery lifetimes for these two sets of sample rates are exemplified below:

Device: Pressure Transmitter, Ambient Temperature 86°F

SAMPLE RATE	ESTIMATED BATTERY LIFE
1 second	0.8 (*less than 1 year*)
16 seconds	7 years

To overcome such challenges a user may supply supplemental solar power. But, this usually requires cabling to an enclosure outside of Class 1 Division 1 areas. There have been recent product entries using energy harvesting techniques. However, applications to date have been limited in the custody transfer area.

For these reasons, current technology has not been conducive to broad use in the Midstream areas.

Upstream Application – Artificial Lift Optimization of a Gas Well

A common application found in the upstream segment involves a technique called Plunger Lift.

During the normal lifecycle of a gas well, the reservoir pressure will eventually decrease to the point that entrained liquids are no longer carried to the surface. Over time these liquids will build up to a point that gas is trapped subsurface and production ceases. Plunger lift is a mechanical means of artificial lift typically used to remove the liquid head from gas wells. This de-liquification process brings produced liquids (water or hydrocarbon) to the surface thereby maintaining gas production. The technique commences by closing the production line valve and allowing the plunger to fall to the bottom of the well. Pressure then begins to build within the well. At some point in time, the production valve is opened and the plunger rises to the surface bringing the liquid head along with it. The valve remains open for a specified period of time to allow the well to produce. When production begins to degrade the valve is closed and the process is repeated.

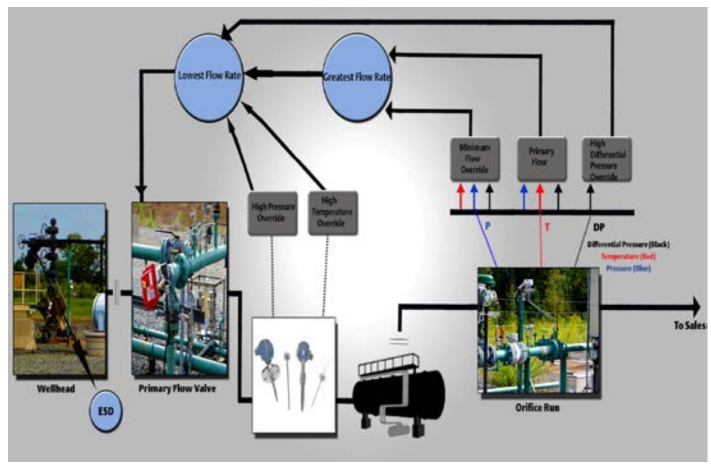
There are several modes of control that may be selected for Plunger Lift control. The most straightforward version is a timer. A timer will simply open a control valve to flow the well for a pre-determined time and then close it to allow the plunger to fall to the bottom. After another set period of time passes to allow pressure to build, the valve is opened and once again the cycle starts anew.

A flow computer can implement a much more sophisticated approach by making use of critical velocity calculations. Critical Velocity, determined by well known Turner and Coleman equations, is the minimum rate of gas flow required from the well to lift liquids. Flow below this value will cause liquids to collect in the well. By using the Turner/Coleman calculations to predict the critical velocity of the gas flow, the computer will not close the production valve while the gas flow rate will still support liquid lift. Therefore, the cycle can be optimized so that a well is produced closer to the limit of its ability.

Upstream Application – Closed Loop Control of a Free Flowing Gas Well

Sizable drilling programs in the shale plays of North America have bought about a massive number of free flowing wells. Maintaining optimal performance for so many sites can prove to be a formidable challenge.

To fulfill this need, producers have flow from each well manipulated via a single automated choke valve. The primary focus of the system is to maintain a steady flow from the well to the Sales Line based upon an operator entered set point. Multiple overrides come into play based upon operating conditions. Measurements include Delta Pressure and Flow Rate from an orifice run feeding a Sales pipeline, and Static Pressure and Temperature of the flow line feeding a separator.



The electronic platform requirements include the ability to execute AGA style flow computations, customized PID (proportional–integral–derivative) control loops, and coded algorithms in addition to communicating with an existing SCADA system. From a hardware perspective, units need to be rugged enough for demanding outdoor environments. Also, lack of electrical power in the area forces reliance upon a solar powered system.

Issues tackled via a Flow Computer

Start-Up Sequencing: Automation can perform an operator determined sequence allowing a consistent, quick, and easy method to achieve minimum flow. Once on-line, an operator has the ability to ramp the flow up over time for a soft landing at the desired flow rate.

Liquid Loading: Whenever slug flow is present, gas flow through the Sales Line will drop as liquid is produced. The primary flow control logic reacts to this change and will open the choke to compensate. When the well unloads (water decreases) the gas flow increases quickly. Once again the primary flow control logic will compensate and commence to close the choke. Reaction time, though, may be too slow to avoid tripping the well off-line due to a high Sales Line pressure. To prevent this type of occurrence, the Delta Pressure (DP) of the orifice run is monitored. A DP override function in the flow computer logic is more aggressively tuned and therefore can bring the well back under normal flow control much sooner.

Maintaining Critical Velocity: Logic within the computer will select between the greater of the primary flow control set point and the Critical Velocity set point. In this fashion, flow will be maintained at the operator set point so long as the Critical Velocity is reached. The control scheme then works to keep the flow rate sufficient to assure that liquids continue to be extracted.

Transient Flow Conditions: To avert the well from being tripped off-line due to a wave of high temperature production, a high temperature override PID loop responds rapidly to lower the flow set point. Reducing the flow through a heat exchanger helps hold the average temperature to an acceptable level. Similarly, any upsets causing a spike in line pressure will trigger a high pressure override response and reduce flow.

ESD: As is always the case for a safe operation, switches located on-site and a remote SCADA command can initiate an Emergency Shutdown (ESD) mode overriding all other logic and causing immediate closure of the choke.

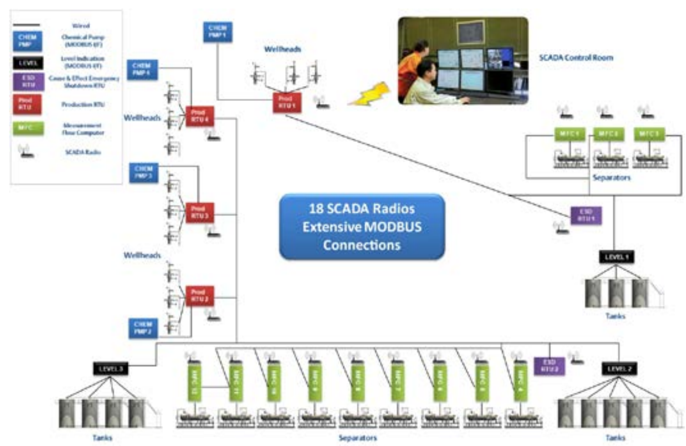
Upstream Application – Distributed Automation manages Multi-Well Pads

Horizontal drilling practices have permitted more than access to long dormant Shale opportunities. The approach also is very conducive for multiple wells to be placed on a single pad. Reduced drilling costs and significantly smaller environmental footprints have resulted. Automation techniques commonly used in the past often become unmanageable when attempting to handle the quantities and densities involved.

Classical automation schemes suffer many drawbacks in this type of scenario including:

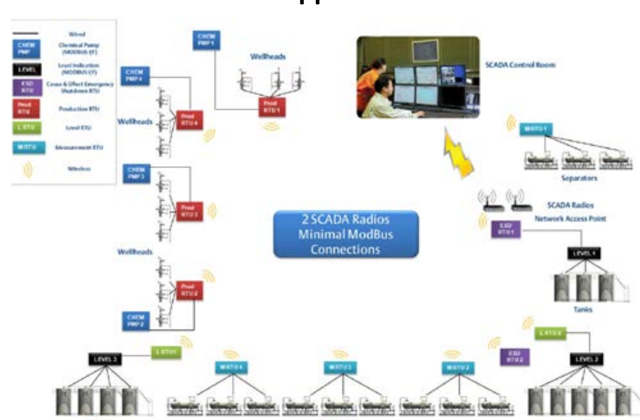
1) Lengthy cable runs
2) Inconsistent data update times
3) Extensive MODBUS register mapping
4) Advance notice of additional drilling

Classical Approach



Wireless Remote Terminal Units (RTUs) acting as nodes on a network can distribute the logic and control functions on a well pad resolving these issues.

Distributed Approach



Benefits include:

- **Elimination of Cabling and Heavy Equipment Trenching**

  Wireless technology eliminates the need to trench and bury conduit between the well head equipment.

- **Minimal MODBUS communications**

  Instead of using hardwired multi-dropped MODBUS communication protocol interfaces and associated registers to map data between RTUs, a distributed system makes use of a Drag-and-Drop technique in its design mode. This means an RTU's database is "browsable" by other RTUs in the network.

- **Scalability**

  A distributed system consists of intelligent nodes each with a capacity to serve their respective purposes, therefore, the system capability automatically grows in proportion to need. In short, once determined to fit a particular use, computing and memory issues are no longer worries.

  From an installation standpoint, the ability to quickly add RTUs to an existing wireless network is a distinct advantage. This ability extends to multiple pad sites within range of the pad, providing the ability to automate production between multiple pad sites.

- **Reduced Deferred Production**

  Usually, automation is one of the last functions placed in service before commencing production. With the distributed system, time to reach first production on a greenfield installation can be reduced by a nominal three days.

- **Lower Total Installed Cost**

  From an equipment perspective, the ability to use a node as an access point to pass through data for other units on the wireless network eliminates additional radios. When combined with diminished cabling and trenching work savings in the millions of dollars can be recognized for large drilling programs.

Take Away

A flow computer is much more than simply a device to calculate flow. Certainly, it can serve as a method for remote retrieval of highly accurate data for Custody Transfer needs. But, units can make use of gathered information to perform sophisticated calculations in order to undertake control activities. Optimization of wellhead production in any stage of well's lifecycle exemplifies this capability.